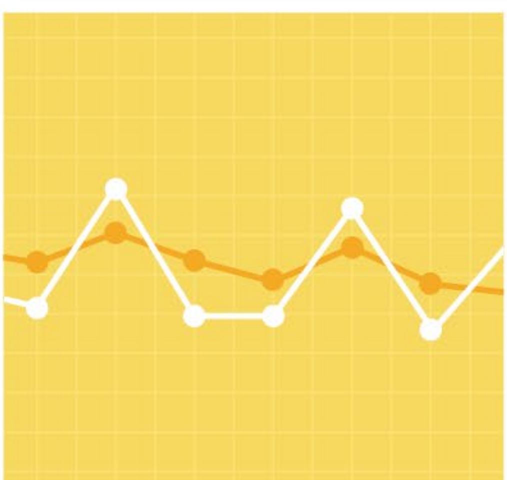
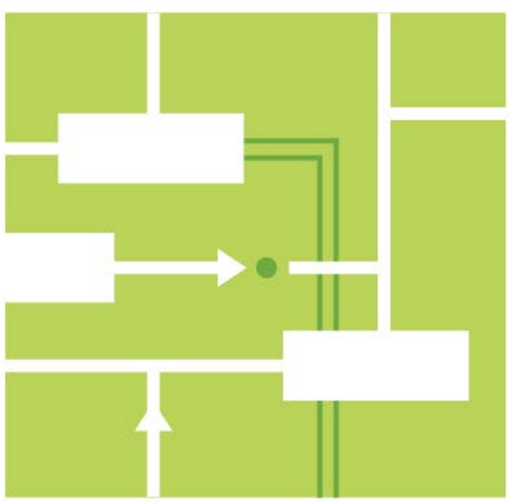
# NPCC 2025 New England Interim Review of Resource Adequacy



Capacity Requirement & Accreditation

Approved by the NPCC RCC on December 1, 2025

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# Executive Summary

ISO New England Inc. (ISO-NE) is the not-for-profit corporation responsible for the reliable and economical operation of New England's bulk power system (BPS). It also administers the region's wholesale electricity markets and manages the comprehensive planning of the regional power system. As part of its planning functions, ISO-NE is the Planning Coordinator for the New England Area of the Northeast Power Coordinating Council (NPCC). One of ISO-NE's responsibilities as a Planning Coordinator is to conduct studies and provide results to demonstrate that the New England's BPS will meet the NPCC resource adequacy criteria as defined in NPCC's Reliability Directory #1 – *Design and Operation of the Bulk Power System*.

This report of *2025 New England Interim Area Review of Resource Adequacy*, covering the years 2026 through 2028, was prepared by ISO-NE to satisfy the NPCC compliance requirements on resource adequacy. This interim report follows the guidelines specified in Appendix D of NPCC Directory #1 entitled *Guidelines for Area Review of Resource Adequacy*.

This 2025 Interim Area Review of Resource Adequacy is the second update from the 2023 Comprehensive Review[1] and covers the period from 2026 through 2028. Changes in assumptions from the 2024 Interim Area Review[2], and the impact of these changes on the overall reliability of the New England electricity system, are highlighted herein.

Results of this Interim Review show that ISO-NE has more than the required amounts of capacity resources through its FCM process to meet the NPCC Full Member Resource Adequacy Criteria for 2026 through 2028 (Capacity Commitment Periods [CCPs] 2026-2027 through 2028-2029).

ISO-NE identifies the amount of installed capacity (the Installed Capacity Requirement [ICR]) needed to meet the regional resource adequacy planning criterion and uses it as a signal regarding resource needs to competitively procure through the Forward Capacity Market (FCM). Through the FCM, the ISO-NE contracts forward with resources such that they are properly located, to the extent possible, to maximize the use of the regional bulk transmission network to serve forecasted loads. Therefore, in addition to the ICR, ISO-NE also develops other *"related values"* or variables to assist in procuring the requisite amount of locational installed capacity resources in the primary Forward Capacity Auction (FCA) and the corresponding annual reconfiguration auctions (ARAs).

ISO-NE modeled the New England system *"at-criterion"* (LOLE set to 0.1 days/year) to establish the required resources to meet the criterion. Then by showing the amount of resources procured from

[1] For details, please see NPCC 2023 New England Comprehensive Review of Resource Adequacy approved by the NPCC Reliability Coordinating Committee (RCC) on December 5, 2023

[2] For details, please see NPCC 2024 New England Interim Area Review of Resource Adequacy approved by the NPCC Reliability Coordinating Committee (RCC) on December 3, 2024

the FCM is at or higher than the ICR[3], demonstrates compliance with both the NPCC and ISO-NE Resource Adequacy Planning Criterion.

## 1.1 Major Findings of this Interim Area Review

For the years 2026-2028, ISO-NE has enough resources through the FCM, such that the amount of installed capacity in New England will remain above the ICR. This in turn confirms that the region is below an LOLE of 0.1 days/year through the study horizon.

The major findings of this *NPCC 2025 New England Interim Area Review* are as follows:

- Through the use of the ICR within ISO-NE's FCM construct and as mandated by its Tariff, ISO-NE has procured or will procure in the future, the requisite supply and demand-side resources needed to adequately meet the NPCC resource adequacy criterion of disconnecting firm load customers no more than 0.1 days/year for each year of the study period under the reference and high demand forecast conditions for the 2026-2028 study horizon. The FCM is not designed to procure sufficient resources for the high demand scenarios, but there are still sufficient resources to meet the imputed ICR for the study horizon.

- The FCM's primary FCA, as well as the corresponding ARAs that have already been conducted, have procured more resources than required by the ICR to meet expected load and required operating reserves through the 2026-2028 timeframe. Although not yet procured through the FCM process, ISO-NE's representative net ICR for the 2028 timeframe identifies the amount of resources needed to satisfy the NPCC resource adequacy planning criterion. In compliance with its Tariff, ISO-NE will procure the ICR in the Capacity Commitment Period 2028-2029 (CCP 19) to satisfy its resource adequacy needs in 2028.

- The capacity market continues to serve as the primary mechanism to create incentives to retain existing and attract new resources in order to meet the NPCC resource adequacy planning criterion.

- As compared to last year's *2024 Interim Area Review*, this year's *2025 Interim Area Review* reflects seasonal peak loads and an annual energy forecast that have been revised slightly downward. Over the next 10-year long term planning horizon (2025-2034), the gross summer and winter peak loads reflect a 10-year compound annual growth rate (CAGR) of 0.95% and 3.32%, respectively. Over the same timeframe, the CAGR of annual gross energy consumption is 2%.

- Over the next 3-year near-term timeframe (2026-2028):
  - The summer net 50/50 peak load (gross peak load net of behind-the-meter solar photovoltaics [BTM PV] during the peak hour and accounting for passive demand response reconstitution in 2026 through 2027[4]) is forecasted to stay relatively steady, from 26,648 MW in 2026 to 26,543 MW in 2028.
  - The winter net 50/50 peak load (gross peak load net of BTM PV during the peak hour [which is zero MW in winter] and accounting for passive demand response reconstitution in 2026 through

[3] Please note that the net ICR (which is equal to the ICR minus the Hydro-Québec Interconnection Capability Credits [HQICCs]) is the amount of actual capacity that ISO-NE procures through the FCM to ensure system reliability. For this report, the general term 'ICR' will be used to refer to the capacity procured in the FCM. The ISO procures the net ICR in the FCM using an auction and a demand curve. The net ICR is a point in the demand curve. For details relating to the FCM auctions, please see: https://www.iso-ne.com/static-assets/documents/100005/20231024-fcm101-lesson-5a-fca_print.pdf

[4] PDR reconstitution for 2028 was not calculated but is expected to be small.

2027) is forecast to grow by 1,376 MW, from 22,790 MW in the winter of 2026/27to 24,166 MW in the winter of 2028/29.

- Total demand resource capacity at the summer peak is forecasted to decrease by 302 MW, from 3,360 MW to 3,058 MW.
- BTM PV reduction during the summer net peak load hour is forecasted to increase by 48 MW, from 1,193 MW to 1,241 MW.
- The 50/50 winter forecast for transportation electrification is forecasted to increase by 188 MW, from 168 MW to 356 MW.
- The 50/50 winter forecast for heating electrification is forecasted to increase by 557 MW, from 435 MW to 992 MW.
- The 50/50 summer forecast for transportation electrification is forecasted to increase by 87 MW, from 87 MW to 174 MW.
- The 50/50 summer forecast for heating electrification is forecasted to increase by 12 MW, from 6 MW to 18 MW.

## 1.2 Summary of Major Assumptions and Results

Table 1-1 shows the major assumptions used in this interim review and Table 1-2 summarizes the resource margin given "at-criterion" system with the reference demand scenario. Table 1-3 summarizes the resource margin given "at-criterion" system with the high demand scenario. The detailed assumptions and results are documented in the later sections of this review.

The assumed available resources are expected to be adequate to meet the NPCC resource adequacy criterion under the reference and high demand forecasts for the study period from 2026 to 2028.

**Table 1-1**
**Major Assumptions**

| Assumptions | Description |
|---|---|
| **Reliability Criterion** | NPCC Criterion: no more than once in 10 years of firm load disconnection (LOLE of 0.1 days/year) |
| **Load Model** | Based on the load forecast from the 2025 Load forecast data (tab 10), which includes the gross forecasts, and the BTM PV forecast. For this report additional load forecast calculations were conducted for the 2028-2029 CCP (50/50 Gross peak load 27,784 MW). |
| **Reliability Model** | GE MARS |
| **Expected Existing Resources** | Including generating resources, energy efficiency resources, active demand capacity resources, and capacity imports/exports as detailed in Section 4.3 |
| **Expected Resource Additions** | Including the NERC Long-Term Reliability Assessment Tier 1 Resources that are under construction and/or have received approved planning requirements in Section 2.2.2.1 |
| **Expected Capacity Retirements** | Resources with retirement requests approved and/or disconnected from the system as specified in Section 2.2.2.2 |
| **Resource Availability (EFORd and Scheduled Maintenance Requirements)** | Generating resources based on their 5-year historical average (Jan 2020 through Dec 2024). Active demand capacity resources based on historical actual and audit performance from 2020 to 2024 |

| | |
|---|---|
| **Tie Benefits Assumptions from Neighboring Systems** | Based on results of the latest tie benefits studies conducted for ISO-NE's FCM as specified in Section 4.4 |
| **Emergency Operating Procedures (Load Relief from Voltage Reduction)** | Assumed 1.0% of load relief from Voltage Reduction during ISO-NE Operating Procedure 4 (OP-4) Actions 6 and 8 |
| **Internal Transmission Constraints** | Subarea representation and the interface limits are detailed in Section 4.4. |

**Table 1-2**
**New England Resource Margin Given "At-Criterion" System with Reference Demand**

| CCP[5] | FCA | Vintage | Reference Summer 50/50 Peak (MW)[6] | Net ICR (MW) | Reserve Margin (%) | FCM Resources (MW)[7] | Resource Margin (MW) |
|---|---|---|---|---|---|---|---|
| **2026-2027** | 17 | ARA3 | 26,648 | **30,050** | 12.8% | 34,998 | **4,948** |
| **2027-2028** | 18 | ARA2 | 26,417 | **29,855** | 13.0% | 34,499 | **4,644** |
| **2028-2029** | 19 | Rep ICR | 26,543 | **30,150** | 13.6% | 33,184 | **3,034** |

**Table 1-3**
**New England Resource Margin Given "At-Criterion" System with High Demand**

| CCP | FCA | Vintage | High Summer 50/50 Peak (MW)[8] [9] | Reserve Margin (%) | Imputed ICR (MW)[10] | FCM Resources (MW) | Resource Margin (MW) |
|---|---|---|---|---|---|---|---|
| **2026-2027** | 17 | ARA3 | 27,363 | 12.8% | 30,856 | 34,998 | **4,142** |
| **2027-2028** | 18 | ARA2 | 27,360 | 13.0% | 30,921 | 34,499 | **3,578** |
| **2028-2029** | 19 | Rep ICR | 27,683 | 13.6% | 31,445 | 33,184 | **1,739** |

[5] The CCP runs from June 1st through May 31st of the next year.

[6] For the 2026-2027 and 2027-2028 CCPs, the reference summer peak loads reflect passive demand resources (PDR) adjustments for ARAs. This is described on slide 7 of the following presentation: https://www.iso-ne.com/static-assets/documents/100028/a02_draft_pspsc_icr_related_values_for_aras.pdf

[7] For the 2028-2029 CCP that has not had an ICR analysis, the FCM resources are assumed to be all existing resources assumed for the 2027-2028 CCP, excluding any cleared Retirement/Permanent de-list bids, and including new generating and demand resources that cleared FCA 18.

[8] High Summer Peak is taking the high 90% confidence interval of the 50/50 reference load forecast.

[9] For the 2026-2027, 2027-2028, and 2028-2029 CCPs, the high summer peak loads account for passive demand resources (PDR) reconstitution.

[10] Imputed ICR is calculated by finding the reserve margin of the system at the reference 50/50 peak and scaling it up proportionally with the high demand scenario.

# Section 2
# Introduction

The *Reliability Assessment and Performance Analysis Program* established by NPCC requires its member Planning Coordinators to conduct resource adequacy assessments on an annual basis. The purpose of this report is to document the results and findings of ISO-NE's interim area review of resource adequacy, covering the period 2026 to 2028, for NPCC review and approval by NPCC's Reliability Coordinating Committee (RCC). ISO-NE conducted the assessment in accordance with the guidelines specified in Appendix D[11] of NPCC Regional Reliability Reference Directory #1, entitled *Design and Operation of the Bulk Power System*. This review supersedes the *2024 New England Interim Area Review of Resource Adequacy.*[12] A comparison between this year's *Interim Review* assumptions versus last year's *Interim Review* assumptions is made within several sections of this report.

## 2.1 Previous New England Interim Area Review

The findings of the 2024 Interim Area Review showed that New England conformed with the NPCC resource adequacy criteria over the study period (2025-2028) under the forecast supply and demand conditions.

## 2.2 Comparison of 2024 Interim Review and 2025 Interim Review

### 2.2.1 Load Forecast

ISO-NE annually updates its load forecast for the next ten years to reflect the impacts from the region's historical use of electric energy and peak loads, and incorporates the most recent economic and demographic forecasts, while adjusting for resettlement that includes meter corrections. The load forecasts used in this review are based on ISO-NE's 2025 Forecast Data spreadsheet. This data contains the following forecasts used as various input assumptions to ISO-NE's resource adequacy compliance determination.

#### *2.2.1.1 The Net Load Forecast*

The seasonal gross peak load and energy forecasts fully account for historical energy efficiency but do not reflect reductions in peak load and energy consumption that result from passive demand resources (PDRs) that clear the FCA, or the BTM PV forecast. For this review, we will be defining 'net load' as our gross peak load forecast minus the BTM PV forecast during the peak hour. This is the load modeled in our resource adequacy analyses. Since energy efficiency (under the form of PDRs) is counted as a resource in the FCM, the gross peak load forecast is not netted out by their reductions. In addition, starting in 2020, ISO-NE began incorporating its electrification forecast (for both heating and transportation sectors) within its gross load forecast. The summer net load 50/50 forecast (gross load net of BTM PV) decreases by 105 MW, from 26,648 MW in 2026 to 26,543 MW in 2028.

[11] Entitled "Guidelines for Area Review of Resource Adequacy."

[12] ISO-NE's *2024 Interim Review* was approved by the NPCC Reliability Coordinating Committee (RCC) on December 3, 2024.

*2.2.1.2 The Behind-the-Meter (BTM) PV Forecast:*

Most of the state-sponsored distributed solar resource installations within New England are connected to the distribution system, so the output of these resources is not directly "visible" to ISO-NE System Operators, however, it does reduce the overall system load observed in real-time. ISO-NE forecasts future BTM PV capacity using a policy-based approach and it is developed with stakeholder input from the Distributed Generation Forecast Working Group (DGFWG). These BTM-PV impacts on reducing the peak load hour are reflected in all NPCC area reviews. The BTM PV forecast peak load reduction grows from 1,193 MW in 2026 to 1,241 MW in 2028, a three-year increase of 48 MW.[13] In this review, the BTM PV is modeled in an hourly profile with uncertainty incorporated to reflect its reliability impacts. The impact from BTM PV during the winter peak hour is zero MW.

*2.2.1.3 The Energy Efficiency (EE) Forecast*

For the next three years, the summer peak load reduction impact from EE is expected to decrease from 2,626 MW in 2026 to 2,394 MW in 2028, a three-year decrease of 232 MW.[14]

It should be noted that for the 2026-2027 and 2027-2028 CCPs, the peak gross load forecast is calibrated to the total CSOs acquired by passive demand capacity resources (DCRs) in the most recent FCA. However, the total CSOs acquired by passive DCRs in the annual reconfiguration auctions (ARAs) often differ from the amount acquired in the FCA for each CCP. Thus, for the purposes of calculating the ICR for the ARAs, additional adjustments must be applied to the forecast to reflect the expected differences in CSOs acquired in the ARAs.[15] An adjustment of 302 MW was added to the summer gross load forecast for the 2026-2027 CCP, and -31 MW for the 2027-2028 CCP. These adjustments are reflected in the net load values used for this review. There are no adjustments for the 2028-2029 CCP.

*2.2.1.4 Reference and High Demand*

This interim review assessed the New England resource adequacy using both the reference and high demand forecasts. The reference and high demand forecasts were developed based on a "most likely" long-run economic and demographic forecast and a high growth long-run economic and demographic forecast, respectively, from Moody's Economy.com.

Since New England is still a summer peaking system through the study horizon, the forecast information presented within this report is for the New England annual peak load, which occurs during the summer season (June-September).

Table 2-1 shows the annual (summer) peak load forecasts used in the 2024 and 2025 reviews for ease of reference and to facilitate comparison. The annual (summer) peaks net of BTM PV are presented for both the reference and high demand forecast scenarios. The peak loads shown in Table 2-1 have a 50% chance of being exceeded (50/50 peaks) due to weather uncertainty. While Table 2-1 shows the annual 50/50 peaks of the forecast, the inherent uncertainty of the load

[13] The cumulative PV nameplate forecast grows from 8,982 MW in 2026 to 10,376 MW in 2028, an increase of 1,394 MW.

[14] These values are based on the QC of passive DR used for ICR calculations.

[15] See the 2023 Long-Term Load Forecast Methodology Overview presentation for more details: https://www.iso-ne.com/static-assets/documents/100003/lf2024_methodology.pdfhttps://www.iso-ne.com/static-assets/documents/100003/lf2024_methodology.pdf

forecast from weather variations is also modeled within the ICR calculation using load uncertainty factors.

**Table 2-1**
**Comparison of Summer Peak Load (50/50) net of BTM PV**

| CCP | 2024 Reference (MW) | 2025 Reference (MW) | Delta 2024 to 2025 (MW) | 2024 High (MW) | 2025 High (MW) | Delta 2024 to 2025 (MW) |
|---|---|---|---|---|---|---|
| **2026-2027** | 26,974 | 26,648 | **-326** | 27,958 | 27,363 | **-595** |
| **2027-2028** | 26,926 | 26,417 | **-509** | 28,126 | 27,360 | **-766** |
| **2028-2029** | 27,178 | 26,543 | **-635** | 28,571 | 27,683 | **-888** |

### 2.2.2 Resources

In New England, generating resources, measurable and verifiable demand side resources (including both passive and active demand resources), and capacity imports are all eligible to participate in ISO-NE's FCM, and if cleared in the primary auction or annual reconfiguration auction, assume Capacity Supply Obligations (CSO) which sum up to meet the region's ICR. This study uses these resources to assess the region's resource adequacy while reflecting the expected year-to-year variations from announced resource additions and retirements. Table 2-2 and Table 2-3 highlight the resource assumptions between the 2024 and 2025 area reviews and a 2025 review breakdown of the resources by category.

**Table 2-2**
**Comparison of 2024 vs. 2025 Existing Capacity Resource Assumptions**

| CCP | FCA | 2024 Vintage | 2024 Review (MW) | 2025 Vintage | 2025 Review (MW) | Delta 2024 to 2025 (MW) |
|---|---|---|---|---|---|---|
| **2026-2027** | 17 | ARA2 | 35,993 | ARA3 | 34,998 | -995 |
| **2027-2028** | 18 | ARA1 | 35,086 | ARA2 | 34,499 | -587 |
| **2028-2029** | 19 | Rep ICR | 32,760 | Rep ICR | 33,184 | 424 |

**Table 2-3**
**Breakdown of 2025 Review Resources Assumptions by Category**

| CCP | FCA | Vintage | Generating Resources (MW) | Demand Resources (MW) | Import Capacity Resources (MW) | Total Resources (MW) |
|---|---|---|---|---|---|---|
| **2026-2027** | 17 | ARA3 | 30,038 | 3,360 | 1,600 | **34,998** |
| **2027-2028** | 18 | ARA2 | 29,706 | 3,208 | 1,585 | **34,499** |
| **2028-2029** | 19 | Rep ICR | 30,042 | 3,058 | 84 | **33,184** |

#### *2.2.2.1 New Resources Since 2024*

Since the 2024 Interim Area Review, several new resources have commercialized operations or plan to commercialize operations within the study horizon. These resources were identified within the 2025 NERC LTRA – Data Form – Form B. Highlights of the new resources that fall within the 2026 – 2028 timeframe, and are greater than 25 MW nameplate include:

<u>New Resources (Existing) since the 2024 interim review (> 25 MW)</u>

- Medway Grid Battery Storage (250 MW Battery)
- Cross Town Battery Storage (175 MW Battery)
- Cranberry Point Energy Storage (150 MW BESS)
- Ocean State Power uprate (73 MW Natural Gas and Other Gases)
- Downeast Wind (126 MW Wind)
- Western Maine Wind Project (58 MW wind)

<u>New Resources (Tier 1) in 2026-2028 (> 25 MW)</u>

- Vineyard Offshore Wind (800 MW) in 2025
- West Springfield 45 MW BESS (45 MW) in 2026
- FPS Panton Solar (50 MW) in 2026
- Revolution Offshore wind (704 MW) in 2026
- Hecate Energy Eastern Ave Energy Center (250 MW) in 2026
- Battery Storage Addition (to QP1086) (160 MW) in 2026
- Warren Meadow Solar (74.5 MW) in 2026
- Naugatuck Avenue Battery Storage (205 MW) in 2026
- Three Rivers Solar (100 MW) in 2026
- Solar Knox (33.5 MW) in 2027
- Energy Storage (170 MW) in 2027
- Broadleaf Solar (101 MW) in 2027
- Green Apple Solar (178 MW) in 2027
- Battery Storage (204 MW) in 2027
- Norman Street Battery Storage (204 MW) in 2028
- Husky Solar (50 MW) in 2028
- Lite Brite Battery Storage (305 MW) in 2028
- Battery Storage (508 MW) in 2028

#### *2.2.2.2 Retirements Since 2024*

Since the 2024 Interim Area Review, several resources have retired or have announced retirements within the study horizon. These resources were identified within the 2025 NERC LTRA – Data Form – Form B. Highlights of the retirements and/or announced retirements that fall within the 2026 – 2028 timeframe, and are greater than 25 MW include:

<u>Retired since the 2024 interim review (> 25 MW)</u>

- WEST SPRINGFIELD GT-1 and GT2 (120 MW gas/oil) in 2025
- Potter 2 CC (101 MW gas-only) in 2025

<u>Announced Retirements in 2026-2028 (> 25 MW)</u>

- Middletown 2 & 3 (353 MW oil) in 2027 (mothballed)

#### *2.2.2.3 Resource Ratings*

The ratings of generating resources used for the development of the ICR were based on the latest available data for each CCP. The 2026-2027 ARA3 used the Qualified Capacity (QC) data from its corresponding ARA2, and 2027-2028 ARA2 used QC data from its ARA1. The 2028-2029 CCP used the FCA 18 existing QC as a base. New generating resources and demand resources that cleared the latest ARA were added to this base. Furthermore, resources with approved retirement and permanent de-list bids were removed.

#### *2.2.2.4 Imports & Exports*

External capacity import resources for 2026 and 2027 used QC values for each respective ARA. If the sum of the import QC was higher than the remaining transmission transfer capability of the external interface after accounting for tie benefits, it was de-rated to the remaining amount. This amounted to 1,600 MW in 2026, and 1,585 MW in 2027. For 2028, only the long-term contract capacity imports of 84 MW were assumed.

#### *2.2.2.5 System Operator Actions for Load and Capacity Relief*

The NPCC Directory #1 resource adequacy requirement #4 allows the use of load and capacity relief from ISO-NE System Operators implementing emergency operating procedures (EOPs) to meet peak system capacity needs. Specifically, load relief from implementing voltage reductions and public appeals are used in meeting the 0.1 days/year LOLE, but are not reflected as resources. Emergency assistance from neighboring regions (tie benefits) are also assumed as an inherit benefit of an interconnected system and those benefits are used to reduce the obligation load has to acquire in the capacity market. Tie benefits assumptions for the most recent ICR and related values study cycle were presented at the ISO-NE Power Supply Planning Committee.

EOPs are documented in ISO-NE System Operating Procedure 4 (OP-4) and associated Appendix A. In actual practice, the operator actions may be implemented in a different order based on the situation and the magnitude of the expected deficiency experienced at the time. OP-4 Actions 1, 2, 5, 6 and 8 were modeled as load relief in this review. OP-4 Actions 3, 4, 7, 9, 10 and 11 were not modeled and are therefore listed as contingency resources. The load relief from implementing a 5% voltage reduction was assumed to be a 1.0% reduction from the corresponding 90/10 peak load net of BTM PV. This equated to roughly 260 MW of relief in the summer and 224 MW of relief in the winter.

# Section 3
# Resource Adequacy Criterion

## 3.1 The New England Resource Adequacy Planning Criterion

The New England ICR is the minimum level of (installed) capacity required to meet the reliability requirements defined for the New England Control Area. Section III.12 of the Tariff (Market Rule 1) documents these requirements as follows:

> *"The ISO shall determine the [ICR] such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period."*

The development of the ICR must also be consistent with Requirement R4 of NPCC Directory #1. Specifically, R4 of Directory 1 states:

> *"R4 Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year.*
>
> *R4.1 Make due allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."*

The net ICR (which is equal to the ICR minus the Hydro-Québec Interconnection Capability Credits [HQICCs]) is the amount of capacity that the ISO procures through the FCM[16] to ensure system reliability.

Typically, the ICR calculations are single-year simulations that the ISO conducts to meet the needs of the FCA and ARAs. The ISO, however, also performs multi-year simulations similar to ICR simulations to assess New England's long-term resource adequacy for the Regional System Plan (RSP)[17].

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[16] The ISO procures the net ICR in the FCM using an auction and a demand curve. The net ICR is a point in the demand curve. For details relating to the FCM auctions, please see:
https://www.iso-ne.com/static-assets/documents/100005/20231024-fcm101-lesson-5a-fca_print.pdf

[17] https://www.iso-ne.com/system-planning/system-plans-studies/rsp

## 3.2 Application of New England Resource Adequacy Planning Criterion

The New England resource adequacy planning criterion is used to determine the installed capacity requirement needed to reliably satisfy system load and required operating reserves. In calculating the amount of resources needed, New England also takes into account the tie benefits that are assumed available from neighboring systems. The tie benefits from Québec, New Brunswick (Maritimes), and New York have been modeled within the ICR model.

To properly capture the intended operation of the system, the emergency operating procedures that are implemented during periods of capacity deficiencies are also modeled in the form of the amount of load relief that is assumed obtainable. It is assumed that the system operators will always maintain at least some minimum level of operating reserve to ensure control over transmission loadings.

## 3.3 Resource Requirements to Meet Resource Adequacy Criterion

As previously shown in Section 2.2.2 (Resources), Table 2-2 shows the breakdown of 2025 Resource Assumptions and Table 2-3 shows the breakdown of 2025 Resource Assumptions by Category.

## 3.4 Methodology Used to Satisfy Resource Adequacy Requirements

For this year's three-year look ahead NPCC Interim Area Review, ISO-NE will use the following reliability assessments to satisfy the Area Review criterion:

**Forward Year 1 (2026) (CCP17/ARA3)** – ISO-NE will use the results of its 2025 Annual Reconfiguration Auction (ARA3) Installed Capacity Requirement (ICR) Analysis which was also presented to the NEPOOL PSPC on October 7, 2025.[18]

**Forward Year 2 (2027) (CCP18/ARA2)** – ISO-NE will use the results of its 2025 Annual Reconfiguration Auction (ARA2) Installed Capacity Requirement (ICR) Analysis which was also presented to the NEPOOL PSPC on October 7, 2025.

**Forward Year 3 (2028) (Representative Net ICR)** – ISO-NE will use the results of its 2025 internal analysis of the representative net Installed Capacity Requirement (ICR).

[18] https://www.iso-ne.com/static-assets/documents/100028/a02_draft_pspsc_icr_related_values_for_aras.pdf

# Section 4
# Resource Adequacy Assessments and the Reliability Model

The following subsections of this interim review will document the resource adequacy assessment assumptions, process, results, and the finer details of the resource adequacy reliability model as performed using the GE MARS program.

## 4.1 Details of the GE MARS Model

GE MARS uses a sequential Monte Carlo simulation to compute the reliability of a power system comprised of a number of interconnected areas containing generation and load. This Monte Carlo process simulates the year repeatedly (multiple replications) to evaluate the impacts of a wide range of possible random combinations of generator outages. The transmission system is modeled in terms of transfer limits (constraints) on the interfaces between interconnected areas. Chronological system histories are developed by combining randomly generated operating histories of the generating units and inter-area transfers with the hourly chronological loads.

For each hour of the year, the program computes the isolated area margins based on the available capacity and demand in each area. GE MARS then uses a transportation algorithm to determine the extent to which areas with negative margin can be assisted by areas having positive (excess) margin, subject to the available transfer constraints between the two areas. The program collects the statistics for computing the reliability indices, and then continues to the next hour. After simulating all of the hours in the year, the program computes the annual indices and tests for convergence. If the simulation has not converged to an acceptable level, it proceeds to another replication of the current study year; otherwise, it moves on to the next study year.

## 4.2 Load Modeling

### 4.2.1 Hourly Loads

GE MARS employs an 8,760-hour chronological sub-area load model. The load model currently relies on actual historical load profiles from the year 2002. This model is then scaled up to the summer peak for the future years being analyzed.

### 4.2.2 Reference Peak Load Forecasts

Table 4-1 shows the three-year forecast of New England's annual summer reference (50/50) gross and net peak load forecast. The gross load forecasts for the 2026-2027, 2027-2028, and 2027-2028 CCPs reflect the PDR reconstitution.

**Table 4-1**
**Annual Summer Reference (50/50) Gross and Net Load Forecasts**

| CCP | Reference Gross (MW) | BTM PV @ Peak Load Hour (MW) | Reference Gross-PV (MW) |
|---|---|---|---|
| **2026-2027** | 27,840 | 1,193 | **26,648** |
| **2027-2028** | 27,625 | 1,208 | **26,417** |
| **2028-2029** | 27,784 | 1,241 | **26,543** |

#### 4.2.3 High Peak Load Forecasts

Table 4-2 shows the three-year forecast of New England's annual summer high (50/50) gross and net peak load forecast. The gross load forecasts for the 2026-2027, 2027-2028, and 2028-2029 CCPs reflect the PDR reconstitution.

**Table 4-2**
**Annual Summer High (50/50) Gross and Net Load Forecasts**

| CCP | High Gross (MW) | BTM PV @ Peak Load Hour (MW) | High Gross-PV (MW) |
|---|---|---|---|
| **2026-2027** | 28,556 | 1,193 | **27,363** |
| **2027-2028** | 28,568 | 1,208 | **27,360** |
| **2028-2029** | 28,923 | 1,241 | **27,683** |

#### 4.2.4 Demand of Entities that are Not Members of ISO-NE Planning Coordinator Area

All the demands of entities within NEPOOL are modeled. The Maine Public Service (MPS) Company's demand (in the northeastern-most area of Maine) is not modeled in this review because it is currently not a part of the ISO Planning Coordinator Area and is fed from the New Brunswick BPS.

#### 4.2.5 Weekly Load Forecast Uncertainty

The load forecast uncertainty was modeled on a seasonal basis, which accounts for the uncertainty due to weather variations. As noted earlier, GE MARS is a probabilistic model. As such, hourly loads are modeled with uncertainty distributions. The ISO develops a forecast distribution of typical daily peak loads for each week of the year. This is based on each week's historical weather distribution combined with an econometrically estimated monthly model of typical daily peak load.

Each weekly distribution of typical daily peak load includes the possible range of daily peaks that could occur over the full range of weather experienced within that week, along with their associated probabilities. Modeling hourly loads with load forecast uncertainty allows GE MARS to develop "per unit" uncertainty multipliers for up to ten different load levels used for computing loads, and to calculate the weighted-average system LOLE reliability indices.

A base load shape was scaled to several different load levels using a set of per-unit multipliers to represent the load uncertainties under a full range of weather conditions. The weather conditions used for deriving the 50/50 and 90/10 peak load forecast are implicitly reflected in these load levels. GE MARS also allows these uncertainty multipliers to vary by month.

### 4.3 Resource Modeling

#### 4.3.1 Resource Ratings

*4.3.1.1 Criteria for Verifying Ratings of Resources*

Seasonal Claimed Capability (SCC) of Generating Units

ISO-NE has the authority to initiate audits of all generating units to verify their Seasonal Claimed Capability (SCC, i.e., maximum MW output of unit). Audits are initiated by ordering the generator output to be increased from its current operating level (if that level is below SCC) to its SCC. The unit is then required to hold the output at its SCC for a predefined time period. The required duration for a claimed capability audit is at least two hours and no more than eight hours, depending on the Capability Period and type of unit. In order to pass a claimed capability audit, a unit must demonstrate it can achieve average output greater than or equal to its Claimed Capability. Full details can be found on the ISO-NE SCC Audit Process webpage or within the ISO-NE Operating Procedure No. 23 – Generator Resource Auditing.

#### Qualified Capacity (QC) Value under FCM

The determination of the QC value of a resource for participation in the FCA is outlined in Section III. 13 – Forward Capacity Market of Market Rule 1.

#### Forward Capacity Auction (FCA) ICR–Related Values Calculations

The ratings of resources were based upon their SCC and QC values.

Existing Capacity Resources are modeled at their existing summer QC. The summer QC of an existing Generating Resource is calculated as the median of the most recent five summer SCC ratings with only positive, non-zero ratings included in the calculation.

Intermittent Power Resources are modeled using summer/winter existing QC. The seasonal QC for Intermittent Power Resources is calculated as the median of the net output during the Seasonal Intermittent Reliability Hours averaged over the most recent five years.

The summer QC of a Demand Resource is rated using the summer seasonal Demand Reduction Value calculation which is dependent upon the Demand Resource type.

#### Annual Reconfiguration Auction (ARA) ICR–Related Values Calculations

All resources are modeled at their QC for the relevant ARA, including New Capacity Resources that have elected critical path schedule (CPS) monitoring to deliver capacity in an earlier CCP than the CCP for which they have qualified to participate in an FCA.

The total amount of QC from Import Capacity Resources that have cleared in the FCA corresponding to the ARA over a transmission interface is limited by the assumed transmission interface limit after accounting for tie benefits.

### 4.3.2 Resource Uncertainty (Unavailability Factors)

#### *4.3.2.1 Types of Unavailability Factors*

Forced outage rates, planned outages, and maintenance outages are represented for each resource in the reliability assessment.

#### *4.3.2.2 Sources of Unavailability Factors*

A five-year, historical average of unit-specific, forced outage assumptions is determined for each generating resource, using its individual unit data of monthly EFORd[19] values from Generating Availability Data System (GADS). GADS data submitted by generators to ISO-NE for the months of January through December is used to create an EFORd value for each unit that submits such data.

[19] The calculation methodology of EFORd can be found in Appendix F of the NERC GADS Data Reporting Instructions at http://www.nerc.com/pa/RAPA/gads/Pages/Data%20Reporting%20Instructions.aspx

NERC GADS class average data is used as a substitute for units that do not submit GADS data to ISO-NE.

Energy efficiency and intermittent resources are assumed 100% available in the reliability model. The availability factors of demand-side resources, such as Active Demand Capacity Resources (ADCR), are based on their performance measured by the actual response during historical events or during ISO-NE claimed capability audits.

A weekly representation of a generator's planned outages is calculated for each unit, based on a five-year historical average. All of the unavailability factors described above associated with each unit/station for the specific FCA/ARA are assumed to be generated from five years' worth of historical maintenance for the five years preceding the year of the FCA/ARA development.

#### *4.3.2.3 Maturity Considerations*

NERC Class Average data is used as a substitute for immature units and new resource additions.

#### *4.3.2.4 Tabulation of Typical Unavailability Factors*

As noted earlier, all of the unavailability factors described herein associated with each unit/station for the specific FCA/ARA are generated from five years' worth of historical maintenance for the five years preceding the year of the FCA/ARA development. The details of each FCA/ARA ICR can be found within ISO-NE's presentations to the NEPOOL PSPC.

The supply- and demand-side unavailability factors for all three years of this analysis can be found within the ISO-NE presentation to the NEPOOL PSPC on August 28, 2025.[20]

### 4.3.3 Demand-Side Programs

The demand side programs included in this assessment include regional conservation and energy efficiency programs, BTM PV, and Active Demand Capacity Resources that participate in New England's FCM.

The BTM PV, including residential and commercial rooftop solar, comprises approximately two-thirds of the total PV capacity and is treated by ISO-NE as a reduction to demand. The BTM PV resources are interconnected to the distribution system, not the bulk power system, and the installation and locational data were historically not available to ISO-NE. As part of long-term forecasting improvement efforts, ISO-NE has established a process to collect town-level installed capacity data from the region's distribution utilities, and applied a policy approach to develop a 10-year forecast of the BTM PV for the region. The 2025 PV forecast was used for this review.[21]

Active Demand Capacity Resources provide real-time peak load relief at the request of ISO-NE System Operators. These resources participate in the FCM and are fully integrated and co-optimized within the energy and reserve markets.

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[20] https://www.iso-ne.com/static-assets/documents/100026/a02_pspc_annual_reconfigurationauction_icr_related_values_development.pdf

[21] https://www.iso-ne.com/static-assets/documents/100022/2025_final_pv_forecast.pdf

#### 4.3.4 Imports and Exports

Table 4-3 summarizes the firm capacity imports, exports, and net of imports/exports, with neighboring systems assumed for each Year/FCA/ARA within this assessment.

**Table 4-3**
**Net Capacity Import & Export Assumptions**

| CCP | FCA | Vintage | Imports (MW) | Exports (MW) | Net (MW) |
|---|---|---|---|---|---|
| **2026-2027** | 17 | ARA3 | 1,600 | 0 | 1,600 |
| **2027-2028** | 18 | ARA2 | 1,585 | 0 | 1,585 |
| **2028-2029** | 19 | Rep ICR | 84 | 0 | 84 |

#### 4.3.5 Existing, New Units, and Announced Retirements

Please see Section 2.2.2.1 of this report to view the list of new units/stations that are commercialized or have announced commercialization within the next three-future years. Please see Section 2.2.2.2 of this report to view the list of units/stations that have retired since the 2024 Interim Review and/or have announced their retirement within the next three-future year window.

#### 4.3.6 Modeling of Variable and Limited Energy Resources

New England's pumped storage and hydro-electric units were considered available to meet daily and monthly peak loads except when they are on planned maintenance or forced outages.

### 4.4 Transmission Modeling

#### 4.4.1 Internal Transmission Sub-Area Modeling

The New England system was modeled as thirteen interconnected sub-areas, with predefined transmission interface limits between them (Figure 4-1). The transmission interface transfer capabilities between these sub-areas have been determined based on established ISO-NE and NPCC reliability criteria. These criteria are described, respectively, in ISO-NE's Planning Procedure No. 3[22], entitled *Reliability Standards for the New England Area Pool Transmission Facilities*, and NPCC Reliability Directory #1, entitled *Design and Operation of the Bulk Power System.* These criteria require that the interconnected bulk power supply system be designed for a level of reliability such that the loss of a major portion of the system, or unintentional separation of any portion of the system, will not result from reasonably foreseeable contingencies. Therefore, the system must be designed to meet representative contingencies as defined in those criteria.

Contingencies are simulated to assess the potential for widespread cascading outages due to overloads, instability, or voltage collapse. New England's bulk power supply system must remain stable during and following the most severe of the contingencies specified in the criteria, with due regard to re-closing facilities and before making any manual system adjustments. Voltages, line loadings, and equipment loadings must be within normal limits for pre-disturbance conditions, and within applicable emergency limits following the contingencies specified in the criteria. Disturbances in New England must not adversely affect other NPCC Control Areas and vice versa.

[22] https://www.iso-ne.com/participate/rules-procedures/planning-procedures

Conversely, the loss of small portions of the system may be tolerated, provided the reliability of the overall interconnected system is not jeopardized.

Since the 2024 Interim review, ISO New England has reflected updated Maine summer transfer limits. As a result of a 325 MW increase to the Orrington-South interface transfer limit, and a 300 MW increase to the Surowiec-South interface transfer limit, the capacity import capability of the NB-NE interface increases by 300 MW (*i.e.,* from 700 MW to 1000 MW).[23]

#### 4.4.2 Internal Transmission Interface Modeling

The transmission interfaces used in this reliability review represent potential limiting areas of New England's transmission system, which may become constrained under a variety of system demands, generation patterns, or transmission topology. The most limiting transmission facility (limiting element) and critical contingency which limits the transmission interface transfer, may change depending on unit dispatch, load level, load distribution, and transmission configuration. For modeling purposes, these interface limits are shown as static. Interfaces composed of one or more transmission facilities have been defined to gauge the amount of power which can be transferred between or through various areas before a transmission limitation is reached. Figure 4-1 shows the internal connections within New England and their respective transfer limits.

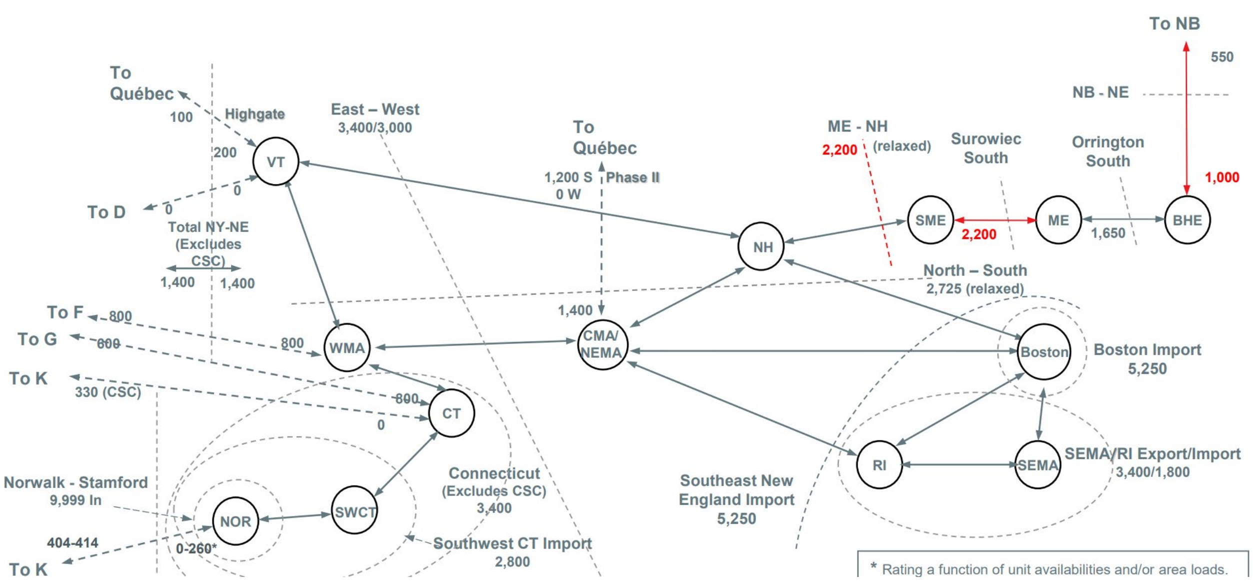


**Figure 4-1: 2025 New England Pipe and Bubble Diagram with Transfer Limits**

[23] https://www.iso-ne.com/static-assets/documents/100013/a04_me_capacity_transfer_capability.pdf

### 4.4.3 External Modeling of Interconnected Systems

New England's directly interconnected neighboring bulk power systems of Québec, Maritimes, and New York provide tie benefits (emergency assistance) and capacity/energy imports in this 2025 interim review. Figure 4-2 shows the external interconnections[24] between regions for tie benefits analysis.

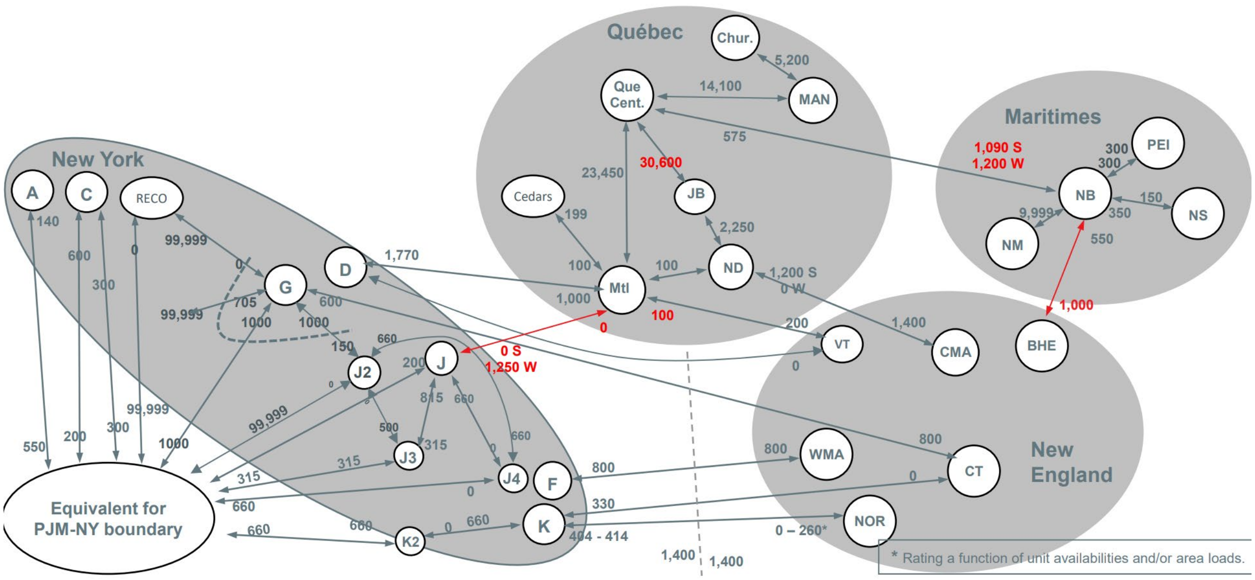


**Figure 4-2: 2025 Interregional Pipe and Bubble Diagram with Transfer Limits**

The tie benefits are derived based on results of studies conducted with the GE MARS program. Within tie benefit studies, all the interconnected Control Areas are assumed to be at the *"at-criterion"* 0.1 days/year resource adequacy criterion simultaneously. The Control Area's load, resources (including load and/or capacity relief assumed available from implementing emergency operating procedures), and transmission interface transfer limits are based on data that each Control Area has provided to NPCC for its regional studies.

After the original tie benefits study for the primary FCA, ISO-NE updates the tie benefit studies for the 3rd ARA of a CCP. The tie benefit assumptions used in this review for 2026 are based on the results of the latest ARA3 tie benefits study. The tie benefits for 2027 use their respective FCA tie benefits analysis. The tie benefits for 2028 are assumed to be the same as FCA 17 ARA3 because the tie benefits study specific to CCP 19 has not been conducted.

The capacity imports, summarized in Section 4.3.4 – Table 4-3, are based on FCM QC and the transmission import capability of the external interconnections after accounting for tie benefits. In other words, the amount of capacity imports that clear in the FCM auctions cannot exceed the transmission import capability of the external interconnections after accounting for emergency

[24] The 2024 Interim Area Review did not include modeling of the New England Clean Energy Connect (NECEC) project because it has not yet completed the steps associated with the achievement of a Capacity Supply Obligation in the Forward Capacity Market.

assistance assumed available over the external interconnections. Table 4-4 below shows the tie benefits assumed for each interconnected area for each year.

**Table 4-4**
**Assumed Tie Benefits from Neighboring Systems**

| Neighboring System (MW) | 2026 CCP 17 ARA3 | 2027 CCP 18 ARA2 | 2028 CCP 19 Rep ICR |
|---|---|---|---|
| Québec (Ph2/HQICCs) | 1,009 | 1,041 | 1,041 |
| Québec (Highgate) | 130 | 136 | 136 |
| New Brunswick | 639 | 544 | 544 |
| New York | 553 | 394 | 394 |
| **TOTAL** | **2,385** | **2,115** | **2,115** |

## 4.5 Other Resource Adequacy Metrics

As part of the annual ICR studies ISO New England gathers additional reliability metrics. These metrics include the loss of load hour measured in hours (LOLH) per year and expected unserved energy (EUE) measured in megawatt hours per year. The LOLH and EUE add additional information on both size (*i.e.,* EUE), frequency and duration (*i.e.,* LOLH) of an energy or capacity shortfall event.

The LOLH and EUE values for the 2024 and 2025 ICR studies can be found in Table 4-5.

- For 2026-2027 CCP the net ICR value and EUE decreased while LOLH increased slightly when comparing 2024 results with 2025 results.
- For 2027-2028 CCP the 2025 net ICR decreased when compared to 2024. While LOLH remained the same, the EUE decreased in 2025.
- For 2028-2029 CCP the 2025 net ICR and EUE increased, while LOLH remained the same when compared to the 2024 results.

**Table 4-5**
**Comparison of New England LOLH and EUE Metrics for the Study Horizon**

| CCP | FCA | 2024 Calculated Values | | | 2025 Calculated Values | | |
|---|---|---|---|---|---|---|---|
| | | Net ICR Calculated (MW) | LOLH (hrs./yr) | EUE (MWh/yr) | Net ICR Calculated (MW) | LOLH (hrs./yr) | EUE (MWh/yr) |
| **2026-2027** | 17 | **30,600** | 0.56 | 843 | **30,050** | 0.58 | 755 |
| **2027-2028** | 18 | **30,415** | 0.57 | 945 | **29,855** | 0.57 | 777 |
| **2028-2029** | 19 | **30,110** | 0.52 | 711 | **30,150** | 0.52 | 835 |

## 4.6 Results of the 2026 - 2028 Resource Adequacy Assessment

For each year of the study horizon, Table 4-6 and Table 4-7 summarize the resource assumptions detailed in Section 2.2.2, along with the corresponding ICR, and resulting resource margin. As shown, New England will meet the resource adequacy criterion of disconnecting firm load customers no more than 0.1 days/year during the three-future year study period for the reference demand scenario.

For the high demand scenario, an imputed ICR is calculated using the reserve margin from the reference demand scenario and multiplying that value by the high demand peak to create an imputed ICR for that higher load level. The FCM is not designed to procure sufficient resources for the high demand scenarios but when compared to the FCM Resources for the study horizon, there are sufficient resources to meet the imputed ICR for the study horizon.

**Table 4-6**
**New England Resource Margin Given "At-Criterion" System with Reference Demand**

| CCP[25] | FCA | Vintage | Ref Summer 50/50 Peak (MW) [26] [a] | Net ICR (MW) [b] | Reserve Margin (%) [c]=([b]/[a])-1 | FCM Resources[27] (MW) [d] | Resource Margin (MW) [e]=[d]-[b] |
|---|---|---|---|---|---|---|---|
| **2026-2027** | 17 | ARA3 | 26,648 | **30,050** | 12.8% | 34,998 | **4,948** |
| **2027-2028** | 18 | ARA2 | 26,417 | **29,855** | 13.0% | 34,499 | **4,644** |
| **2028-2029** | 19 | Rep ICR[28] | 26,543 | **30,150** | 13.6% | 33,184 | **3,034** |

**Table 4-7**
**New England Resource Margin Given "At-Criterion" System with High Demand**

| CCP | FCA | Vintage | High Summer 50/50 Peak (MW)[29 30] [a] | Reserve Margin (%) [b] | Imputed ICR (MW)[31] [c]=[a]*[1+b] | FCM Resources (MW) [d] | Resource Margin (MW) [e]=[d]-[c] |
|---|---|---|---|---|---|---|---|
| **2026-2027** | 17 | ARA3 | 27,363 | 12.8% | **30,856** | 34,998 | **4,142** |
| **2027-2028** | 18 | ARA2 | 27,360 | 13.0% | **30,921** | 34,499 | **3,578** |
| **2028-2029** | 19 | Rep ICR | 27,683 | 13.6% | **31,445** | 33,184 | **1,739** |

25 The CCP runs from June 1st through May 31st of the next year.

26 For the 2026-2027 and 2027-2028 CCPs, the reference summer peak loads reflect passive demand resources (PDR) adjustments. This is described on slide 7 of the following presentation: https://www.iso-ne.com/static-assets/documents/100028/a02_draft_pspsc_icr_related_values_for_aras.pdf.

27 For the 2028-2029 CCP that has not had an ICR analysis, the FCM resources are assumed to be all existing resources assumed for the 2027-2028 CCP, excluding any cleared Retirement/Permanent de-list bids, and including new generating and demand resources that cleared FCA 18.

28 Rep ICR = Representative net ICR.

29 High Summer Peak is taking the high 90% confidence interval of the 50/50 reference load forecast.

30 For the 2026-2027 and 2027-2028 CCPs, the high summer peak loads reflect passive demand resources (PDR) adjustments. This is described on slide 7 of the following presentation: https://www.iso-ne.com/static-assets/documents/100028/a02_draft_pspsc_icr_related_values_for_aras.pdf.

31 Imputed ICR is calculated by finding the reserve margin of the system at the reference 50/50 peak and scaling it up proportionally with the high demand scenario.

The results indicate that ISO New England has procured capacity in excess of the calculated ICR for the New England system. The ICR is calculated to meet the NPCC resource adequacy criterion of disconnecting firm load customers no more than 0.1 days/year for each year of the study period. The excess capacity beyond the ICR for the 2026-2028 study horizon further reduces the loss of load expectation (LOLE) of the New England system to below 0.1 days/year.

# Section 5
# Conclusion

ISO-NE identifies the amount of installed capacity (the Installed Capacity Requirement [ICR]) needed to meet the regional resource adequacy planning criterion and uses it as a signal regarding resource needs to competitively procure through the Forward Capacity Market (FCM). Through the FCM, the ISO-NE contracts forward with resources such that they are properly located, to the extent possible, to maximize the use of the regional bulk transmission network to serve forecasted loads. Therefore, in addition to the ICR, ISO-NE also develops other *"related values"* or variables to assist in procuring the requisite amount of locational installed capacity resources in the primary Forward Capacity Auction (FCA) and the corresponding annual reconfiguration auctions (ARAs).

ISO-NE modeled the New England system *"at-criterion"* (LOLE set to 0.1 days/year) to establish the required resources to meet the criterion. Then by showing the amount of resources procured or expected to be procured from the FCM is at or higher than the ICR, demonstrates compliance with both the NPCC and ISO-NE Resource Adequacy Planning Criterion.

For the years 2026-2028, ISO-NE has procured or is expecting to procure enough resources through the FCM, such that combined with other due allowances, the amount of installed capacity in New England will remain above the ICR. This in turn confirms that the region is below an LOLE of 0.1 days/year through the study horizon.